DIRECT TESTIMONY

of

Mike Luth
Rate Analyst

Rates Department
Financial Analysis Division
Illinois Commerce Commission

Petition for approval of delivery services tariffs and tariff revisions and of residential delivery services implementation plan and for approval of certain other amendments and additions to its rates, terms and conditions.

Commonwealth Edison Company

Docket No. 01-0423

August 23, 2001

Witness Identification

Q. Please state your name and business address.

A. Mike Luth, Illinois Commerce Commission, 527 East Capitol Avenue, Springfield, Illinois 62701.

Q. What is your present position with the Illinois Commerce Commission?

A. I am currently a Rate Analyst in the Rates Department of the Financial Analysis Division. In that position, I review and analyze tariff filings by electric, gas, water and wastewater utilities with regard to cost of service and rate design. I make recommendations to the Commission on such filings and participate in docketed proceedings as assigned. In this docket, I evaluated the cost of service and rate design aspects of the Delivery Services Tariffs ("DST") filed by Commonwealth Edison Company ("Edison" or the "Company).

Q. Please state your professional qualifications and work experience.

A. I received a B.S. in Accounting from Illinois State University. I have earned the C.P.A and C.M.A professional designations. Since graduating, I have worked as an Assistant Property Manager with a real estate company and as a Field Auditor with the Wisconsin Department of Revenue. In October of 1990, I joined the Accounting Department of the Illinois Commerce Commission ("Commission"). In June 1998, I transferred from the Accounting Department of the Commission to the Rates Department.

Q. Have you testified in any previous Commission dockets?

A. Yes. I have testified on numerous occasions before the Commission.

Introduction to Testimony

Q. What is the subject matter of your testimony?

A. My testimony presents the results of my analysis of the embedded Cost of Service Study ("COSS") prepared by Edison witness Heintz (Edison Exhibit Nos. 14.0, 14.1, 14.2 and 14.3). Mr. Heintz' COSS allocates distribution costs to rate classes, and classifies those costs as customer or demand-related for each rate class. Mr. Heintz' COSS is prepared on an embedded cost basis, as opposed to a marginal cost basis. As a result of my review, I recommend certain changes to the COSS prepared by Mr. Heintz which affect the allocation of costs between rate classes, and also affect the classification of costs within the rate classes as customer or demand-related. I will discuss my recommended changes to Mr. Heintz' COSS and also discuss the recommended rates that result from the revised COSS.

Q. Are you sponsoring any schedules as part of your testimony?

A. Yes, I am.

Schedule 1 Cost of Service and Rate Design

Embedded vs. Marginal Costs

Q. What is the difference between an embedded COSS and a marginal COSS?

A. An embedded COSS allocates distribution costs, or delivery services costs, among rate classes based upon allocation factors applied to distribution and customer-related sub-functions. The sub-functions are developed by allocation factors applied to the balances accumulated in the Company's accounting records. The accounts are organized according to the Uniform System of Accounts for Electric Utilities Operating in Illinois. (83 Ill. Adm. Code 415) The system of accounts provides a segregation of costs among the primary electric utility functions of production, transmission, distribution, customer service, and administrative and general support.

A marginal COSS seeks to assign costs among rate classes according to an estimate of the costs caused by incremental changes in the level of peak electrical demand and the number of customers. (ComEd Ex. 13.0, page 50, lines 170-178) Total revenues to be recovered from the combined rate classes under a marginal COSS are not different from the total revenues recovered under an embedded COSS, but the contribution to total revenues of each rate class differs under the marginal COSS compared to the embedded COSS.

Q. Do any other Staff witnesses discuss the comparison of marginal cost allocation vs. embedded cost allocation?

A. Yes, Staff witness Lazare (ICC Staff Exhibit No. 7.0) presents a general discussion of why Staff supports an embedded COSS instead of a marginal COSS in this docket.

Q. Are there any problems with Edison's marginal COSS in this docket?

A. Yes. In general, a marginal COSS represents a mismatch between cost allocation and the embedded costs to be recovered. One of Edison's main points of support for a marginal COSS is the concept of "Cost causer pays." (ComEd Ex. 2.0, page 11, lines 292-295) The embedded costs to be recovered from delivery services determined in this docket are the result of accumulated costs caused by the activities of the various classes of customers. Measuring those costs is appropriately based upon the activities that caused, and continue to cause, those costs. However, ComEd's marginal COSS does not look at the costs actually incurred on the ComEd system, but rather looks at the costs that a hypothetical new customer may impose on the distribution system by connecting to the distribution system. An embedded COSS measures actual costs, rather than hypothetical costs, based upon the activities (demand for electricity) that caused the costs that are to be recovered. In that sense, an embedded COSS better approximates the "Cost causer pays" concept.

Q. Are there any other problems with Edison's marginal COSS?

A. Yes, while the Company explains that the purpose of a marginal COSS is to measure the incremental cost caused by incremental demands for electricity, the Company's filing does not reflect that concept. Edison's demand and consumption billing determinants are weather-normalized, that is, the billing units have been increased for a number of customer classes to account for the effects of weather in a "normal" year compared to weather of the test year. The increase in weather-normalized billing units does not result in an increase in expenses. The Company indicated that billing units are not tied to revenue requirement. (Staff data requests GEG 4.01 and 4.02) This suggests that distribution costs fit more into the category of fixed costs that do not vary with a level of activity, instead of variable or marginal cost, which vary with a change in activity. (ComEd Ex. 2.0, page 14, lines 373-388) This calls into question the role of a marginal cost study in explaining the incurrence of distribution costs on the ComEd system, particularly for existing customers who increase their demand.

Q. Does Edison's marginal COSS provide the "price signals" that Edison discusses as another reason for using a marginal COSS over an embedded COSS?

A. No, it does not. While Edison states that tariffs based upon a marginal COSS ". . . will send appropriate price signals, which will tend to lead to efficient choices by all parties, . . ." (ComEd Ex. 2.0, page 11, lines 282 and 283), the price signals sent by Edison's marginal COSS have at least as much to do with a customer's location on the distribution system as it does with the hypothetical customer's delivery services rate class. Edison's marginal COSS is based upon an averaging of a wide range of costs within a given rate class. Edison's marginal COSS divides most delivery services rate classes according to four locations defined by distribution density. The four distribution density locations are 0-2,500 kVA per square mile, 2,501-15,000 kVA per square mile, 15,001-30,000 per square mile and 30,001+ kVA per square mile. (ComEd Exhibit 13.1, page 15)

For the Residential Single Family No Space Heat class, which is the class with the highest level of marginal costs in Edison's marginal COSS, (ComEd Exhibit 13.1, page 3) coincident peak related distribution investment cost ranges from $381 to $1,355 per kW, depending upon the density of the customer's location in the distribution system. (Id., page 12) Dividing $1,355 by $381 results in a quotient of more than 3.5, which means that customers in the most expensive distribution density locations have an estimate of current equipment costs that average more than 3.5 times higher than the estimate of current distribution equipment costs in the least expensive distribution density areas. For the highest marginal cost non-residential class, which is the 100-400 kW class, the range is $280 to $758 per kW, which is a quotient of 2.7, or nearly triple the costs of similar customers located in different distribution density areas.

Within Edison's rate classes, the Company's proposed tariffs based upon its marginal COSS do not reflect these differences resulting from the hypothetical customer's location. For example, there is no price signal for a potential new residential customer to locate in the low-cost medium light instead of a high-cost light distribution density area, although Edison's marginal COSS indicates that the lower-cost medium-light distribution density area would have the least-cost impact upon the distribution system.

Q. How does marginal, or incremental, growth in the distribution system occur?

A. Incremental growth in the use of a distribution system occurs under two scenarios: increased demand by existing, currently connected customers, and connection of additional customers, if existing customers with similar demand aren't lost.

Q. Do the rates derived from Edison's marginal COSS distinguish between the two sources of incremental, or marginal, growth?

A. No, the rates do not distinguish between the sources of incremental growth. In order to serve the incremental demands of new customers connecting to the distribution system, the Company may be required to incur a host of distribution costs. However, the cost of serving incremental demands by existing customers whose distribution facilities are already in place could be much lower or even zero if there is sufficient capacity in their geographical area. For example, the distribution costs associated with serving incremental demands of residential customers in a stable Chicago neighborhood could be far less than the cost of meeting the incremental demands by customers in a new subdivision in a rapidly-growing suburb. The lack of a change in costs resulting from weather-normalized demand billing units indicates that pricing of delivery services for existing customers based upon a determination of marginal costs is not appropriate, because incremental usage of the distribution system resulting from differences in weather do not incrementally increase costs.

Q. Should Edison's marginal COSS be used to determine delivery services rates in this docket, or should an embedded COSS be used?

A. An embedded COSS should be used to determine delivery services rates in this docket. To base delivery services rates upon the same marginal cost calculation for existing customers and new customers within the same rate class does not make sense, yet that is what Edison's proposed delivery services rates suggest. The marginal COSS could theoretically have some use in determining rates for newly connected customers based not only upon customer size or demand, but also upon location. This would at least triple the number of rate classes, which would most likely be difficult to administer as well as complicating the understandability of the delivery services tariffs. Furthermore, as customers moved into the low-cost distribution density area based upon the price signals sent by the marginal COSS, the distribution density of the area would change, invalidating the price signal sent by the marginal COSS. An embedded COSS, using appropriate allocation factors for each cost description, is a better model for determining delivery services rates designed to recover the embedded revenue requirement under review in this docket.

<u>Schedule 1</u>

Q. Please explain Schedule 1, Cost of Service and Rate Design.

A. Schedule 1 is an embedded COSS which is based upon the COSS presented by Edison witness Heintz, with changes. (ComEd Exhibit 14.1, Schedule 2a, pages 11 and 12) One difference between Schedule 1 and the COSS that Mr. Heintz prepared is that I have built the design of rates into my COSS. Mr. Heintz does not propose rates based upon his COSS.

Q. Does Mr. Heintz' COSS recover the entire amount of the Company's proposed revenue requirement?

A. No, it does not. Mr. Heintz' COSS allocates approximately $1,783,662,608 which is less than the Company's proposed revenue requirement of $1,786,970,000.

Q. How did you address the additional revenues to be recovered through the rates that you designed based upon the COSS that you developed?

A. In order to recover additional revenues based upon the COSS that I prepared, I increased the total cost of service for each distribution sub-function shown on pages 11 and 12 of ComEd Exhibit 14.1, Schedule 2a by a multiple of 1.0018543. This multiple was determined by dividing the Company's proposed $1,786,970,000 revenue requirement by the $1,783,662,608 total cost of service allocated by Mr. Heintz' COSS. The product that results for each distribution sub-function is further adjusted by the Staff revenue requirement factor, which is determined by dividing the Company's proposed revenue requirement by Staff's revenue requirement.

Q. Did you change the allocation and recovery of the Illinois Electricity Distribution Tax and System Black Start costs?

A. Yes, I did. First, I changed the allocation factor "KWH-ALL" which is used to allocate the Illinois Electricity Distribution Tax and System Black Start costs. Mr. Heintz' allocation factor included the loss factor for each individual rate class, which has the effect of increasing kWh billing units. The tax is based upon kWh at the meter, which does not include adjustment for loss factors. Since the tax is not based upon loss factor-adjusted kWh, the tax should be allocated among the rate classes based upon metered kWh's. The revised allocation is shown in the first two lines of Schedule 1, pages 1 and 2.

I have also set up the recovery of the Illinois Electricity Distribution Tax and System Black Start costs solely through the variable demand-related charge for each rate class, rather than recovery through both the demand charge and the customer charge, as was done by Mr. Heintz. Both of these costs are related to the use of the distribution system, rather than the customer's connection to the distribution system, so it is appropriate to recover the entire amount of these costs through the demand charge.

Q. Have you adjusted the Company's proposed High-voltage Delivery Services credit, referred to as Rider HVDS?

A. Yes, I have. I have developed a High-voltage rate for each rate class where it may be applicable, that is, those classes that have demand metering capability. This is different from the Company's proposed credit, which acts as a reduction of the demand rate paid by each rate class. The High-voltage rate applies to those customers within each rate class who take delivery service at 69 kV or higher. It is appropriate to charge these customers a lower demand rate because high-voltage customers do not use distribution equipment designed to reduce electricity delivered below 69 kV. A specific rate for the High-voltage customers in each rate class, such as I have developed, is more direct, and therefore more understandable than a rate that applies to all customers in a rate class, reduced by a credit for high-voltage service, as Edison proposes. The High-voltage rate that I have calculated applies to demand billing units. High-voltage customers pay the same monthly customer charge as other customers in their rate class under my rate design.

Q. How did you determine the High-voltage rate?

A. The High-voltage rate starts with the high-voltage demand characteristics of the over-10,000 kW rate class, which is the same rate class which serves as the basis for Edison's proposed HVDS credit. I did not have high-voltage demand characteristics for the other rate classes, but the over-10,000 kW rate class accounts for 94% of the high-voltage demand billing units on the Edison distribution system, so that class serves as a good surrogate for developing a High-voltage demand rate to be available to other rate classes.

Once I developed the High-voltage demand rate, I added the high-voltage percentage of demand uncollectible accounts, Illinois Electricity Distribution Tax and System Black Start costs for each rate class. The high-voltage percentage of these costs for each rate class is determined by dividing the high-voltage demand billing units for each rate class by total demand billing units for each rate class. The High-voltage demand uncollectible accounts, Illinois Electricity Distribution Tax and System Black Start costs for each rate class were then summed, and then divided by High-voltage demand billing units for each rate class to determine a per-kW rate for these costs. The per-kW rate was then added to the high-voltage demand rate developed from the over-10,000 kW rate class to determine the High-voltage rate for each rate class.

In designing rates for each rate class, total high-voltage demand revenues served as a reduction of revenues to be recovered from other customers in each rate class. High-voltage revenues are thus separated from lower-voltage revenues, so that high-voltage customers do not pay for costs that are allocated to lower-voltage customers, and conversely, lower-voltage customers do not pay for costs that are allocated to high-voltage customers.

Rate Design

Q. Please explain how you calculated rates on Schedule 1.

A. Total cost of service is allocated among the delivery services rate classes according to demand or customer sub-function. Demand costs are recovered by a per-kW or per-kWh charge, with the total amount charged based upon demand or consumption during the monthly billing period. Customer costs are recovered through a fixed monthly customer charge for each rate class. The monthly customer charge is not affected by monthly differences in demand or consumption. Metering costs are unbundled from customer costs to allow the customer the opportunity to obtain metering services from an alternative metering services provider, and are also recovered through a fixed monthly metering charge. If a delivery services customer obtains metering services from an alternative metering services provider, the customer does not pay the monthly metering charge, but is subject to the monthly customer charge and the demand charge.

Once the separate demand, customer and metering-related costs are totaled for each rate class, the costs are divided by the appropriate billing units for each rate class. Demand costs are divided by unratcheted billing demand, measured in kW, for the test year. Residential and a small general service rate classes do not have demand metering capability, so the demand charge for those rate classes are determined by dividing demand costs by kWh consumption for the test year. Customer and Metering costs are divided by the average number of monthly bills in a delivery services rate class in the test year to yield the monthly customer charge.

Q. What do you mean when you say that demand costs are divided by unratcheted demand billing units?

A. Unratcheted demand billing units are based upon the demand by the customer class in each month, which are summed together for an annual total. Each customer pays demand costs based upon the demand reading for each month. Ratcheted demand billing units are based upon each customer's peak demand reading for a given period, for example 30 minutes of demand in the month of July. The customer is charged for demand costs based upon that reading for a longer given period, such as in this docket, a year. Total annual unratcheted demand billing units are lower than total annual ratcheted demand billing units because the unratcheted annual total is based upon the demand readings for each month, rather than the peak demand readings for each customer during the year, as is the case under ratcheted demand billing rate design.

In this docket Edison has proposed a 12-month ratchet period, which could mean that a customer would be charged for demand costs in March based upon a peak demand reading in the previous July, even if the customer's demand in March was half of the demand reading in July. If the customer had taken energy-reducing measures, or if an economic downturn occurred where the customer's demand reading was lowered between the previous July and the next 12 months, the customer's demand billing would remain based upon the previous July demand reading. The customer would have to wait until the following July to get relief from demand charges based upon a peak demand in the previous July, or 12 months. Conversely, if the customer had a higher demand reading in the most recent July, or in any month during the interim, the demand billing ratchet would be increased, thereby increasing the monthly demand billing for the next 12 months, because of a higher peak demand. A demand ratchet is quickly responsive to an increase in peak demand, but has a time lag for decreases in peak demand.

Q. Did Edison propose a ratcheted demand in the previous delivery services docket, Docket No. 99-0117?

A. Yes, as in this docket, Edison proposed a 100%, 12-month ratchet billing period, with the demand ratchet based upon 100% of the highest 30-minute demand reading during demand peak periods. Demand peak periods were defined in that docket, and is defined in Edison's proposal in this docket, from 9 a.m. to 6 p.m., Monday through Friday, with the exception of holidays. Under

Edison's proposal, a delivery services customer subject to a 12-month 100% demand billing ratchet would thus pay demand charges throughout the year based upon the 30-minute peak demand reading over the past 12 months.

Q. Did the Commission accept Edison's 12-month, 100% demand ratchet in its Order in Docket No. 99-0117?

A. No, it did not. The Commission agreed with Staff's arguments against the demand ratchet, indicating that customers have no control over their delivery services bills for a year and would be required to pay demand charges during an economic downturn based upon demand occurring during an earlier period when electrical demand resulting from greater economic activity was higher. (Order, Docket No. 99-0117, page 64) The Commission also indicated that ratchets had not been favorably reviewed by the Commission for more than 15 years. (Id.)

Q. Is there any justification for a billing ratchet, whether it is a 100% ratchet or some lowered percentage?

A. Theoretically, there may be some support for a partial ratchet, given that a distribution system should be planned to meet each customer's electrical demand, whenever that demand may occur. A partial ratchet, combined with partial demand billing for current month demand, would recognize both the need for the distribution system to be available when required, and the benefit to the distribution system on the whole by reduced energy demand from an individual customer.

On a practical level, however, support for a ratchet becomes more difficult. There are concerns about the relationship of the timing of demand with demand billing. In the summer, the distribution system may be more apt to break down from demand spikes for air conditioning by residential and small commercial customers who are not subject to demand metering, but Edison's proposed ratchet does not recognize this possible link. Another concern is how to measure the percentage of distribution system costs affected by non-coincident peak from individual customers, and the percentage affected by coincident peak from the combined demand of all customers on the distribution grid. Moreover, Edison indicated in Docket No. 99-0117 that it did not have the capability to develop billing units for a partial demand ratchet, (Order, Docket No. 99-0117, page 63) and has indicated similar difficulties in this docket. (Edison reply to Staff data request ML-4)

Given the practical constraints on implementing a partial ratchet, the theoretical support is insufficient in favor of a partial ratchet. There is nothing new in Edison's proposed ratchet compared to the ratchet proposed and rejected in the last delivery services docket. Edison's proposed 100% ratchet is not an appropriate substitute for a properly designed partial ratchet, and should not be used to design rates in this docket. Edison's proposed ratchet is not responsive enough in the short-term to changes in demand from efficiency improvements or slumped economic conditions.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

		Allocator	Total ICC	Single Family w/o SH	Single Family w/SH	Multi Family w/o SH	Multi Family w/SH	GS No Demand	GS 0-25 kw	GS 26-100 kw	GS 101-400 kw	GS 401-800 kw
			0.8926350									
	ADDITIONS											
1	Illinois Electricity Distribution Tax	KWH-ALL	94,074,089	19,136,070	1,094,725	4,002,860	1,980,770	747,506	3,863,965	7,380,785	10,815,415	8,601,568
2	System Black Start	KWH-ALL	386,333	78,586	4,496	16,439	8,134	3,070	15,868	30,311	44,416	35,324
3	TOTAL COST OF SERVICE (Revenue-Related Undistributed)		1,595,111,979 1,595,111,979	592,798,403	24,945,043	163,833,627	58,459,216	20,501,720	69,199,443	100,154,153	131,589,559	93,228,502
	DEMAND-RELATED COST OF SERVICE (Reduced for Other Revenues)											
4	High Voltage ESS		12,409,274	0	0	0	0	0	0	0	0	14,214
5	High Voltage Dist. Substations		253,852,631	85,098,579	4,309,268	15,560,115	9,518,868	2,196,416	10,750,784	19,469,425	26,467,311	18,981,026
6	High Voltage Dist. Lines		35,620,025	11,450,387	579,831	2,093,682	1,280,805	295,537	1,446,565	2,619,697	3,561,293	2,555,694
7	Distribution Substations		107,307,485	36,007,721	1,823,378	6,583,944	4,027,714	929,368	4,548,974	8,238,088	11,199,101	8,031,432
8	Distribution Lines		653,817,576	219,392,720	11,109,727	40,115,546	24,540,602	5,662,581	27,716,606	50,194,141	68,235,396	48,934,998
9	Line Transformers		73,614,229	24,858,646	1,258,806	4,545,357	2,780,613	641,608	3,140,475	5,687,328	7,731,522	5,544,659
10	Uncollectible Accounts		8,856,598	1,865,938	162,933	3,647,651	837,477	58,138	300,646	602,439	673,045	429,085
11	Revenue-related		(13,100,118)	(4,450,687)	(217,622)	(867,306)	(488,838)	(120,976)	(597,120)	(990,024)	(1,306,032)	(929,131)
12	Illinois Electricity Distribution Tax and System Black Start		94,460,422	19,214,656	1,099,221	4,019,299	1,988,904	750,576	3,879,833	7,411,096	10,859,830	8,636,892
13	Total Demand-related Costs		1,226,838,122	393,437,961	20,125,541	75,698,287	44,486,145	10,413,247	51,186,765	93,232,190	127,421,465	92,198,868
14	Less: High-voltage Revenues		19,403,578	-	-	-	-	-	-	-	697	21,632
15	Net Demand-related Costs <69 kV)		1,183,716,262	393,437,961	20,125,541	75,698,287	44,486,145	10,413,247	51,186,765	93,232,190	127,420,768	92,177,236
16	Divided by: Unratcheted Demand billing units (<69 kV)			18,085,441,483	1,052,574,530	3,757,622,321	1,931,763,743	693,286,760	13,557,695	22,077,986	28,494,232	19,038,553
17	Rate			$ 0.02175	$ 0.01912	$ 0.02015	$ 0.02303	$ 0.01502	$ 3.77548	$ 4.22286	$ 4.47181	$ 4.84161
	- per kWh or kW			per kWh	per kWh	per kWh	per kWh	per kWh	per kW	per kW	per kW	per kW

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

		Allocator	GS 801-1000 kw	GS 1001-3000 kw	GS 3001-6000 kw	GS 6001-10000 kw	GS Over 10000 kw	Fixt. Incl. Ltg	Street Lighting Dusk to Dawn	All Other Lighting	Railroads	Water/Sewer Pumping
	ADDITIONS											
1	Illinois Electricity Distribution Tax	KWH-ALL	2,531,652	11,090,361	6,536,154	3,070,195	11,243,129	138,482	527,217	96,985	483,107	733,144
2	System Black Start	KWH-ALL	10,397	45,545	26,842	12,608	46,172	569	2,165	398	1,984	3,011
3	TOTAL COST OF SERVICE (Revenue-Related Undistributed)		28,287,942	112,812,057	63,498,093	27,708,268	68,705,330	16,345,802	7,453,913	735,811	7,069,919	7,785,176
	DEMAND-RELATED COST OF SERVICE (Reduced for Other Revenues)											
4	High Voltage ESS		1,509	57,628	309,254	556,572	11,470,097	0	0	0	0	0
5	High Voltage Dist. Substations		5,814,635	22,189,069	12,685,540	5,532,965	10,210,125	389,138	1,475,428	127,882	1,600,825	1,475,232
6	High Voltage Dist. Lines		782,567	2,992,586	1,744,188	791,515	2,743,688	52,360	198,525	17,207	215,398	198,499
7	Distribution Substations		2,460,344	9,388,850	5,367,626	2,277,992	4,278,317	164,656	624,297	54,111	677,356	624,214
8	Distribution Lines		14,990,715	57,205,657	32,704,601	13,879,656	26,067,511	1,003,237	3,803,802	329,694	4,127,089	3,803,296
9	Line Transformers		1,698,547	6,481,779	3,705,648	1,572,657	2,953,621	113,673	430,996	37,356	0	430,939
10	Uncollectible Accounts		123,703	67,249	36,505	16,235	31,197	516	1,471	294	-	2,075
11	Revenue-related		(283,096)	(1,077,504)	(618,772)	(269,446)	(635,212)	(23,984)	(71,854)	(6,243)	(71,631)	(74,637)
12	Illinois Electricity Distribution Tax and System Black Start		2,542,049	11,135,905	6,562,996	3,082,803	11,289,301	139,051	529,382	97,383	485,091	736,155
13	Total Demand-related Costs		28,130,972	108,441,219	62,497,585	27,440,948	68,408,645	1,838,649	6,992,048	657,685	7,034,129	7,195,772
14	Less: High-voltage Revenues		-	62,248	314,551	645,483	18,358,967					
15	Net Demand-related Costs <69 kV)		28,130,972	108,378,971	62,183,034	26,795,466	50,049,679					
16	Divided by: Unratcheted Demand billing units (<69 kV)		5,470,816	22,384,760	12,346,201	5,428,188	9,984,179		combined with customer costs below	combined with customer costs below	1,318,375	combined with customer costs below
17	Rate - per kWh or kW		$ 5.14201 per kW	$ 4.84164 per kW	$ 5.03661 per kW	$ 4.93636 per kW	$ 5.01290 per kW	see page 9, this schedule			$ 5.33545 per kW	

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

0.8926350

		Allocator	Total ICC	Single Family w/o SH	Single Family w/SH	Multi Family w/o SH	Multi Family w/SH	GS No Demand	GS 0-25 kw	GS 26-100 kw	GS 101-400 kw	GS 401-800 kw
1	Uncollectible Accounts - High Voltage Share	HV/Total									10	288
2	Revenue-related - High Voltage Share	HV/Total									(20)	(623)
3	Illinois Electricity Distribution Tax and System Black Start - High Voltage Share	HV/Total									163	5,789
4											154	5,454
5	Divided by: Unratcheted High-voltage billing units										429	12,770
6											$ 0.35890	$ 0.42710
7	Plus: High Voltage Demand Rate										1.26685	1.26685
8	Total High Voltage Demand Rate								$ 1.62575	$ 1.62575	$ 1.62575	$ 1.69395
9	Unratcheted High-voltage billing units								0	0	429	12,770
10	High-voltage Revenues								$ -	$ -	$ 697	$ 21,632
11												
12												
13												
14												
15												
16												

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

		Allocator	GS 801-1000 kw	GS 1001-3000 kw	GS 3001-6000 kw	GS 6001-10000 kw	GS Over 10000 kw	Fixt. Incl. Ltg	Street Lighting Dusk to Dawn	All Other Lighting	Railroads	Water/Sewer Pumping
1	Uncollectible Accounts - High Voltage Share	HV/Total	-	109	526	1,030	15,784					
2	Revenue-related - High Voltage Share	HV/Total	-	(1,741)	(8,908)	(17,098)	(321,382)					
3	Illinois Electricity Distribution Tax and System Black Start - High Voltage Share	HV/Total	-	17,991	94,481	195,621	5,711,754					
4			-	16,359	86,099	179,553	5,406,156					
5	Divided by: Unratcheted High-voltage billing units		0	36,223	180,332	367,786	10,224,419					
6			$ 0.43936	$ 0.45161	$ 0.47744	$ 0.48820	$ 0.52875					
7	Plus: High Voltage Demand Rate		1.26685	1.26685	1.26685	1.26685	1.26685					
8	Total High Voltage Demand Rate		$ 1.70620	$ 1.71846	$ 1.74429	$ 1.75505	$ 1.79560					
9	Unratcheted High-voltage billing units		0	36,223	180,332	367,786	10,224,419					
10	High-voltage Revenues		$ -	$ 62,248	$ 314,551	$ 645,483	$ 18,358,967					

HVDS RATE (based upon over 10,000 kW class)

11	High Voltage ESS	11,470,097
12	High Voltage Dist. Substations	94,516
13	High Voltage Dist. Lines	1,388,153
14	High Voltage Demand Costs	12,952,766
15	Divided by: Unratcheted High Voltage Demand billing units	10,224,419
16	High Voltage Demand Rate per kW	$ 1.26685

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

0.8926350

		Allocator	Total ICC	Single Family w/o SH	Single Family w/SH	Multi Family w/o SH	Multi Family w/SH	GS No Demand	GS 0-25 kw	GS 26-100 kw	GS 101-400 kw	GS 401-800 kw
	CUSTOMER-RELATED COST OF SERVICE (Reduced for Other Revenues)											
1	Services		25,631,010	18,161,466	708,939	1,665,640	415,514	423,505	562,434	519,431	1,860,464	415,081
2	Customer Install. Other		54,968,994	32,114,578	725,465	14,580,795	2,354,956	1,698,131	2,255,195	800,785	264,774	59,073
3	Fixt.-Incl. Ltg.		14,515,114	-	-	-	-	-	-	-	-	-
4	Billing -- Computation & Data Mang.		146,578,850	82,578,818	1,865,447	37,492,780	6,055,488	4,366,541	5,798,966	2,059,123	680,836	151,899
5	Bill Issue & Processing		23,406,921	13,675,043	308,918	6,208,800	1,002,788	723,099	960,308	340,991	112,746	25,154
6	Customer Information		14,672,355	8,572,042	193,642	3,891,914	628,586	453,266	601,958	213,746	70,674	15,768
7	Uncollectible Accounts		4,555,179	768,058	32,469	3,379,831	207,783	45,817	64,286	27,492	17,169	3,404
8	Revenue-Related		(3,384,516)	(1,831,994)	(43,367)	(803,626)	(121,284)	(95,340)	(127,680)	(45,179)	(33,315)	(7,372)
9	Total Customer-related Costs		280,943,907	154,038,011	3,791,512	66,416,134	10,543,832	7,615,019	10,115,467	3,916,388	2,973,348	663,008
10	Divided by: Monthly bills, except Pumping Class kWh			24,692,283	557,791	11,210,889	1,810,676	1,305,660	1,733,977	615,702	203,585	45,417
11	Monthly Customer Charge			$ 6.24	$ 6.80	$ 5.92	$ 5.82	$ 5.83	$ 5.83	$ 6.36	$ 14.60	$ 14.60
	- Lighting and Pumping Class on a per-kWh basis, all others a fixed monthly charge			per month	per month	per month	per month	per month	per month	per month	per month	per month
12	METERING SERVICES		87,329,950	45,322,431	1,027,991	21,719,205	3,429,239	2,473,454	7,897,211	3,005,575	1,194,747	366,626
13	Divided by: Monthly bills, except Lighting and Pumping Class kWh			24,692,283	557,791	11,210,889	1,810,676	1,305,660	1,733,977	615,702	203,585	45,417
14	Monthly Metering Charge, except Lighting and Pumping Class kWh			$ 1.84	$ 1.84	$ 1.94	$ 1.89	$ 1.89	$ 4.55	$ 4.88	$ 5.87	$ 8.07
15	TOTAL COST OF SERVICE		$ 1,595,111,979	$ 592,798,403	$ 24,945,043	$ 163,833,627	$ 58,459,216	$ 20,501,720	$ 69,199,443	$ 100,154,153	$ 131,589,559	$ 93,228,502

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

		Allocator	GS 801-1000 kw	GS 1001-3000 kw	GS 3001-6000 kw	GS 6001-10000 kw	GS Over 10000 kw	Fixt. Incl. Ltg	Street Lighting Dusk to Dawn	All Other Lighting	Railroads	Water/Sewer Pumping
	CUSTOMER-RELATED COST OF SERVICE (Reduced for Other Revenues)											
1	Services		70,953	159,032	34,848	9,195	-	-	321,112	34,059	-	269,337
2	Customer Install. Other		10,098	21,866	4,791	1,264	1,327	28,140	27,827	9,567	31	10,332
3	Fixt.-Incl. Ltg.		-	-	-	-	-	14,515,114	-	-	-	-
4	Billing -- Computation & Data Mang.		25,965	3,909,863	856,765	226,052	237,215	144,715	71,555	24,601	5,653	26,567
5	Bill Issue & Processing		4,300	9,311	2,040	538	565	11,982	11,850	4,074	13	4,400
6	Customer Information		2,695	5,836	1,279	337	354	7,511	7,428	2,554	8	2,758
7	Uncollectible Accounts		548	2,809	581	157	129	4,408	99	39	-	100
8	Revenue-Related		(1,254)	(44,999)	(9,851)	(2,599)	(2,635)	(204,717)	(4,837)	(825)	(62)	(3,581)
9	Total Customer-related Costs		113,306	4,063,717	890,455	234,944	236,955	14,507,154	7,427,082	731,753	5,644	7,505,684
10	Divided by: Monthly bills, except Pumping Class kWh		7,761	16,813	3,688	964	1,021		482,239,768	88,711,232	840	672,591,581
11	Monthly Customer Charge		$ 14.60	$ 241.70	$ 241.45	$ 243.72	$ 232.08		$ 0.01540	$ 0.00825	$ 6.72	$ 0.01116
	- Lighting and Pumping Class on a per-kWh basis, all others a fixed monthly charge		per month	per month	per month	per month	per month		per kWh	per kWh	per month	per kWh
12	METERING SERVICES		43,663	307,122	110,053	32,375	59,730	-	26,831	4,058	30,146	279,492
13	Divided by: Monthly bills, except Lighting and Pumping Class kWh		7,761	16,813	3,688	964	1,021		482,239,768	88,711,232	840	672,591,581
14	Monthly Metering Charge, except Lighting and Pumping Class kWh		$ 5.63	$ 18.27	$ 29.84	$ 33.58	$ 58.50		$ 0.00006	$ 0.00005	$ 35.89	$ 0.00042
15	TOTAL COST OF SERVICE		$ 28,287,942	$ 112,812,057	$ 63,498,093	$ 27,708,268	$ 68,705,330	$ 16,345,802	$ 7,453,913	$ 735,811	$ 7,069,919	$ 7,785,176

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

0.8926350

		Allocator	Total ICC	Single Family w/o SH	Single Family w/SH	Multi Family w/o SH	Multi Family w/SH	GS No Demand	GS 0-25 kw	GS 26-100 kw	GS 101-400 kw	GS 401-800 kw
	REVENUES AS BILLED											
1	Demand Rate			$ 0.02175	$ 0.01912	$ 0.02015	$ 0.02302	$ 0.01501	$ 3.77548	$ 4.22286	$ 4.47181	$ 4.84161
2	Multiplied by: Demand Billing Units			18,085,441,483	1,052,574,530	3,757,622,321	1,931,763,743	693,286,760	13,557,695	22,077,986	28,494,232	19,038,553
3	Demand Revenues			$ 393,358,352	$ 20,125,225	$ 75,716,090	$ 44,469,201	$ 10,406,234	$ 51,186,806	$ 93,232,244	$ 127,420,792	$ 92,177,249
4	High-Voltage Demand Rate			$ -	$ -	$ -	$ -	$ -	$ 1.62575	$ 1.62575	$ 1.62575	$ 1.69395
5	Multiplied by: High-Voltage Billing Units			-	-	-	-	-	-	-	429	12,770
6	High-Voltage Demand Revenues			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 697	$ 21,632
7	Monthly Customer Charge			$ 6.24	$ 6.80	$ 5.92	$ 5.82	$ 5.83	$ 5.83	$ 6.35	$ 14.60	$ 14.61
8	Multiplied by: Monthly Bills			24,692,283	557,791	11,210,889	1,810,676	1,305,660	1,733,977	615,702	203,585	45,417
9	Customer Charge Revenues			$ 154,079,846	$ 3,792,979	$ 66,368,463	$ 10,538,134	$ 7,611,998	$ 10,109,086	$ 3,909,708	$ 2,972,341	$ 663,542
10	Monthly Meter Charge			$ 1.84	$ 1.84	$ 1.94	$ 1.89	$ 1.89	$ 4.55	$ 4.88	$ 5.87	$ 8.07
11	Multiplied by: Monthly Bills			24,692,283	557,791	11,210,889	1,810,676	1,305,660	1,733,977	615,702	203,585	45,417
12	Metering Charge Revenues			$ 45,433,801	$ 1,026,335	$ 21,749,125	$ 3,422,178	$ 2,467,697	$ 7,889,595	$ 3,004,626	$ 1,195,044	$ 366,515
13	Total Revenues as Billed		$ 1,595,112,006	$ 592,871,999	$ 24,944,539	$ 163,833,677	$ 58,429,513	$ 20,485,929	$ 69,185,488	$ 100,146,577	$ 131,588,874	$ 93,228,938
14	Total Revenues Allocated		1,595,111,979	592,798,403	24,945,043	163,833,627	58,459,216	20,501,720	69,199,443	100,154,153	131,589,559	93,228,502
15	Excess/(deficit)		$ 27	$ 73,596	$ (504)	$ 51	$ (29,703)	$ (15,791)	$ (13,955)	$ (7,576)	$ (685)	$ 436

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

		Allocator	GS 801-1000 kw	GS 1001-3000 kw	GS 3001-6000 kw	GS 6001-10000 kw	GS Over 10000 kw	Fixt. Incl. Ltg	Street Lighting Dusk to Dawn	All Other Lighting	Railroads	Water/Sewer Pumping
	REVENUES AS BILLED											
1	Demand Rate		$ 5.14201	$ 4.84164	$ 5.03661	$ 4.93636	$ 5.01290	see page 9,	$ 0.01539	$ 0.00825	$ 5.33545	$ 0.01115
2	Multiplied by: Demand Billing Units		5,470,816	22,384,760	12,346,201	5,428,188	9,984,179	this schedule	482,239,768	88,711,232	1,318,375	672,591,581
3	Demand Revenues		$ 28,130,991	$ 108,378,949	$ 62,182,999	$ 26,795,490	$ 50,049,691		$ 7,421,670	$ 731,868	$ 7,034,124	$ 7,499,396
4	High-Voltage Demand Rate		$ 1.70620	$ 1.71846	$ 1.74429	$ 1.75505	$ 1.79560	$ -	$ -	$ -	$ -	$ -
5	Multiplied by: High-Voltage Billing Units		-	36,223	180,332	367,786	10,224,419	-	-	-	-	-
6	High-Voltage Demand Revenues		$ -	$ 62,248	$ 314,551	$ 645,483	$ 18,358,967	$ -	$ -	$ -	$ -	$ -
7	Monthly Customer Charge		$ 14.61	$ 241.71	$ 241.45	$ 243.72	$ 232.08	$ -			$ 6.72	
8	Multiplied by: Monthly Bills		7,761	16,813	3,688	964	1,021	-			840	
9	Customer Charge Revenues		$ 113,388	$ 4,063,870	$ 890,468	$ 234,946	$ 236,954	$ -			$ 5,645	
10	Monthly Meter Charge		$ 5.63	$ 18.27	$ 29.84	$ 33.58	$ 58.50	$ -	$ 0.00006	$ 0.00005	$ 35.89	$ 0.00042
11	Multiplied by: Monthly Bills		7,761	16,813	3,688	964	1,021	-	482,239,768	88,711,232	840	672,591,581
12	Metering Charge Revenues		$ 43,694	$ 307,174	$ 110,050	$ 32,371	$ 59,729	$ -	$ 28,934	$ 4,436	$ 30,148	$ 282,488
13	Total Revenues as Billed		$ 28,288,073	$ 112,812,241	$ 63,498,068	$ 27,708,290	$ 68,705,340	$ 16,345,750	$ 7,450,604	$ 736,303	$ 7,069,916	$ 7,781,885
14	Total Revenues Allocated		28,287,942	112,812,057	63,498,093	27,708,268	68,705,330	16,345,802	7,453,913	735,811	7,069,919	7,785,176
15	Excess/(deficit)		$ 132	$ 184	$ (25)	$ 22	$ 10	$ (52)	$ (3,309)	$ 492	$ (2)	$ (3,292)

COMMONWEALTH EDISON COMPANY
COST OF SERVICE STUDY AND RATE DESIGN

TEST YEAR ENDED DECEMBER 31, 2000

FIXTURE-INCLUDED LIGHTING

1	Staff COSS Total Costs allocated	$ 16,345,802
2	Divided by: Company COSS Total Cost allocated	18,312,538
3	Adjustment Factor	0.89260

	Charge per Fixture Municipal Street Lighting:	Billing Units	Co. Proposed Rate	Adjustment Factor	Staff Rate	Revenues
4	Mercury Vapor -- 100 watts	252,558	$ 5.05	0.89260	$ 4.51	$ 1,139,037
5	175 watts	649,128	5.62	0.89260	$ 5.01	3,252,131
6	250 watts	104,106	6.21	0.89260	$ 5.54	576,747
7	400 watts	118,194	7.43	0.89260	$ 6.63	783,626
8	High Pressure Sodium -- 70 watts	16,662	$ 5.59	0.89260	$ 4.98	$ 82,977
9	100 watts	189,972	5.47	0.89260	$ 4.88	927,063
10	150 watts	188,640	5.86	0.89260	$ 5.23	986,587
11	250 watts	131,922	6.92	0.89260	$ 6.18	815,278
12	400 watts	25,020	8.12	0.89260	$ 7.25	181,395
13	1,000 watts	1,644	17.56	0.89260	$ 15.67	25,761
14	Special Equipment -- Bracket <8 feet	905,808	$ 2.64	0.89260	$ 2.36	$ 2,137,707
15	Bracket >8 feet	622,254	5.37	0.89260	$ 4.79	2,980,597
16	Luminaire -- Post Top (Early American/Contemporary)	51,426	$ 2.57	0.89260	$ 2.29	$ 117,766
17	Luminaire -- Acorn	4,782	6.98	0.89260	$ 6.23	29,792
	Charge per Fixture Private Outdoor Lighting:					
18	Mercury Vapor -- 175 watts	136,799	$ 6.07	0.89260	$ 5.42	$ 741,451
19	400 watts	47,865	8.25	0.89260	$ 7.36	352,286
	High Pressure Sodium Flood --					
20	100 watts	26,930	$ 7.85	0.89260	$ 7.01	$ 188,779
21	250 watts	121,142	8.67	0.89260	$ 7.74	937,639
	High Pressure Sodium Conventional -					
22	100 watts	5,373	$ 6.06	0.89260	$ 5.41	$ 29,068
23	400 watts	10,464	6.43	0.89260	$ 5.74	60,063
24		3,610,689				$ 16,345,750